Decision 05-12-045 December 15, 2005

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39-E) for Adoption of its 2006 Energy Resource Recovery Account (ERRA) Forecast Revenue Requirement and for Approval of Its 2006 Ongoing Competition Transition Charge (CTC) Revenue Requirement and Rates.	Application 05-06-007 (Filed June 1, 2005)

DECISION ADOPTING THE 2006 FORECAST REVENUE REQUIREMENT FOR PACIFIC GAS AND ELECTRIC COMPANY'S ENERGY RESOURCE RECOVERY ACCOUNT AND COMPETITION TRANSITION CHARGE

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O P I N I O N

1. Summary

This Decision adopts a forecast revenue requirement in 2006 of $2.483 billion for Pacific Gas and Electric Company's (PG&E's) Energy Resources Recovery Account (ERRA) and $340.0 million for PG&E's ongoing Competition Transition Charge (CTC). The following Table compares the 2006 forecast revenue requirement adopted by today's Decision to PG&E's previously adopted 2005 forecast revenue requirement:

Adopted 2006 and 2005 Forecast Revenue Requirement for PG&E's ERRA and Ongoing CTC				
	2006 ($000)	**2005 ($000)**	**Difference**	
			($000)	**(%) Increase**
ERRA	2,482,823	2,252,000	230,823	10.25%
Ongoing CTC	340,006	218,581	121,425	55.55%
Combined	2,822,829	2,470,851	352,248	14.26%

The revenue requirement adopted by today's Decision will be (1) revised in December 2005 in accordance with PG&E's Annual Electric True-Up (AET) process to reflect updated estimates of the end-of-year balances in the ERRA and the modified Transition Cost Balancing Account (MTCBA), and (2) incorporated into PG&E's electric rates on January 1, 2006, via the AET process.

This Decision also adopts PG&E's proposed rate design to recover the adopted forecast revenue requirement for the ERRA and ongoing CTC. Finally, this Decision determines that the statutory method should be used to determine the ongoing CTC revenue requirement.

2. Procedural Background

PG&E filed Application (A.) 05-06-007 on June 1, 2005. PG&E asks the Commission to act on A.05-06-007 in time for PG&E to change rates on January 1, 2006, to ensure timely recovery of its electricity procurement costs in 2006.

Notice of A.05-06-007 appeared in the Commission's Daily Calendar on June 6, 2005. The following parties submitted a protest, a prehearing conference statement, written testimony, briefs, and/or comments on the proposed decision:

- The Alliance for Retail Energy Markets (AReM)
- The San Francisco Bay Area Rapid Transit District (BART)
- The California Municipal Utilities Association (CMUA)
- California Large Energy Consumers Association (CLECA)
- Californians for Renewable Energy (CARE)[1]
- The Merced Irrigation District & the Modesto Irrigation District (jointly, Merced & Modesto)
- The Northern California Power Agency (NCPA)
- The Office of Ratepayer Advocates (ORA)[2]
- The South San Joaquin Irrigation District (SSJID)

A prehearing conference was held on August 10, 2005, and the Assigned Commissioner issued a scoping memo on August 25, 2005. An evidentiary hearing was held on October 4, 2005. This proceeding was submitted with the receipt of reply briefs on October 21, 2005.

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[1] CARE withdrew from the proceeding on September 19, 2005.

[2] ORA filed a protest but did not participate thereafter.

3. Summary of Application 05-06-007

A. Forecast Revenue Requirement for the ERRA

The purpose of the ERRA is to enable PG&E to recover from bundled service customers the costs that PG&E incurs to provide electricity to these customers pursuant to a Commission-approved plan. Under the ERRA ratemaking mechanism, PG&E files an application to adopt a forecast revenue requirement for the ERRA for the upcoming calendar year. PG&E then files another application to true-up the forecast revenue requirement collected in rates with PG&E's actual costs to procure electricity. The instant proceeding addresses PG&E's forecast revenue requirement for 2006.

The costs recorded in the ERRA include fuel for utility retained generation (URG), electricity purchased from Qualifying Facilities (QF) and others, and California Independent System Operator (CAISO) charges. Excluded from the ERRA are costs for existing California Department of Water Resources (DWR) contracts allocated to PG&E and the base costs for PG&E's URG assets.

In A.05-06-007, PG&E seeks authority to recover in 2006 a forecast revenue requirement for the ERRA in the amount of $2.821 billion. The following Table summarizes PG&E's request:

Summary of PG&E's 2006 Forecast Revenue Requirement for the ERRA	
Item	**($000)**
1. Fuel Costs for PG&E Retained Generation	170,854
2. QF, Other Purchased Power, CAISO, & Other Costs	2,763,986
3. Total ERRA Costs	2,934,840
4. Franchise Fees and Uncollectibles @ .009602	28,180
5. Total ERRA Revenue Requirement	2,963,020
6. Less: Costs Transferred to MTCBA	(23,777)
7. Less: Amortization of 2005 Year-End ERRA Balance	(118,342)
Total Forecast ERRA Revenue Requirement	**2,820,901**

Summary of PG&E's 2006 Forecast Revenue Requirement for the ERRA	
Item	**($000)**
Source: PG&E Supplement Filed Nov. 2, 2005, Table 6-6.	

The projected 2005 year-end ERRA balance in Line 7 of the above Table will be updated in December 2005 via the AET process. PG&E's requested revenue requirement of $2.821 billion exceeds by $569 million PG&E's authorized 2005 ERRA forecast revenue requirement of $2.252 billion. The main reason for the increase in 2006 is that PG&E projects the cost of natural gas used to generate electricity will be much higher in 2006 compared to 2005.

PG&E's forecasted revenue requirement for the ERRA is based on projected load, the resources available to meet the projected load, and the cost of these resources. PG&E reduced its forecasted revenue requirement by (i) the projected 2005 year-end overcollection in the ERRA of $118.3 million, and (ii) the projected amount of ERRA-related costs transferred to the MTCBA. The costs transferred to MTCBA are recovered via the ongoing CTC, which is addressed *infra*. Application 05-06-007 provides a detailed explanation of each component of PG&E's forecasted ERRA revenue requirement.

B. Forecast Revenue Requirement for the Ongoing CTC

The purpose of the ongoing CTC[3] is to recover the costs authorized by Pub. Util. Code § 367(a)(1) – (6).[4] These costs include (i) power acquired from third parties in 2006 under contracts that were in effect on December 20, 1995, at a price that exceeds the current market price of electricity, (ii) QF contract

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[3] Ongoing CTC is also known as "tail CTC."

[4] All statutory references are to the Public Utilities Code unless otherwise indicated.

restructuring costs, and (iii) amortization of the year-end balance in the MTCBA. The MTCBA tracks ongoing CTC costs and revenues.[5] The net amount is passed through to bundled, direct access (DA), and certain departing load (DL) customers. Decision (D.) 03-07-030 ordered PG&E to include its forecast revenue requirement for the ongoing CTC in the annual ERRA forecast proceeding.

PG&E requests authority to recover in 2006 a forecast revenue requirement for the ongoing CTC in the amount of $1.927 million. The following Table summarizes PG&E's request:

Summary of PG&E's 2006 Forecast Revenue Requirement for the Ongoing CTC	
Item	**($000)**
1. Above-Market Costs	2,760
2. QF Contract Restructuring Costs	20,790
3. Franchise Fees & Uncollectibles @ .009602	226
4. Subtotal	23,776
5. Amortization of 2005 Year-End MTCBA Balance	(21,849)
Total Forecast Revenue Requirement	**1,927**
Source: PG&E Supplement Filed Nov. 2, 2005, Tables 6-2, 6-3, and 6-4.	

The costs in Lines 1 and 2 of the above Table are initially recorded in the ERRA and then transferred to the MTCBA. The projected 2005 year-end MTCBA balance in Line 5 of the above Table applies only to bundled and DA customers. This year-end balance will be updated in December 2005 via the AET process. The MTCBA balance for DL customers will be addressed in Rulemaking (R.) 02-01-011. Application 05-06-007 provides a detailed explanation of each component of PG&E's forecasted revenue requirement for the ongoing CTC.

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[5] CTC is an element of the Cost Responsibility Surcharges (CRS).

PG&E's requested revenue requirement for the ongoing CTC in 2006 is a decrease of $216.7 million from PG&E's authorized forecast revenue requirement for 2005. The main reason for the decrease is that PG&E's revenue requirement for 2005 included amortization of a substantial undercollection in the MTCBA.

PG&E calculated the above-market component of ongoing CTC in Line 1 of the above Table by comparing the projected cost of electricity recorded in the ERRA to a market benchmark. In previous years, the Commission used the California Energy Commission's (CEC) 20-year levelized cost of owning and operating a combined cycle gas-fired generation turbine (CCGT) as a proxy for the market price of electricity. However, an updated CEC CCGT was not available for this proceeding. In lieu of the CEC CCGT, the parties agreed that the market price of electricity should be determined by the Commission's Energy Division using the 20-year baseload Market Price Referent (MPR) adopted in Resolution E-3942. The MPR utilizes a cash flow model for a CCGT that is similar to the CEC's model. The parties further agreed that (1) the non-gas inputs used to determine the MPR should be the same as those adopted in Resolution E-3942, and (2) the 20-year gas price forecast used to determine the MPR should be computed using the forecasting model adopted by the Commission in R.04-04-025, updated to reflect the most recent market data from the New York Mercantile Exchange. The market-price of electricity using the MPR with the previously described inputs is $72.70/MWh.[6]

PG&E used the "total portfolio method" to forecast the ongoing CTC revenue requirement for bundled and DA customers. Under this method, the

[6] PG&E supplement filed on November 2, 2005, Attachment 2.

forecast cost of PG&E's portfolio of resources, including URG,[7] is compared to the cost of the "market portfolio." The cost of the market portfolio is equal to the forecasted gigawatt-hours (GWh) provided by PG&E's portfolio multiplied by the MPR. The cost of PG&E's resources in excess of the market portfolio are considered "above market" and recorded as ongoing CTC. Other CTC-eligible costs, such as eligible QF contract restructuring costs, are added to the above-market costs to develop the total ongoing CTC revenue requirement. Finally, a portion of the ongoing CTC revenue requirement is allocated to bundled and DA customers based on the ratio of bundled and DA load to total load.

PG&E's calculation of the forecast ongoing CTC revenue requirement for bundled and DA customers using the total portfolio method is shown in the following Table:

PG&E's Forecast of the 2006 Ongoing CTC Revenue Requirement for Bundled & DA Customers Using the Total Portfolio Method			
Item	**MPR**	**(GWh)**	**($000)**
1. URG		29,630	1,094,658
2. QFs & Purchased Power Eligible for Ongoing CTC		18,924	1,896,894
3. Irrigation Districts & Water Agencies		3,741	88,476
4. **Total Portfolio Generation & Cost**		**52,295**	**3,080,028**
5. MPR Benchmark ($/MWh)	$72.70		
6. Market Cost (Line 4 (GWh) x Line 5)			$3,801,847
7. Above Market Costs (Line 4 - Line 6)			$0
8. Restructuring Costs			20,790
9. Total Portfolio Revenue Requirement			20,790
10. Revenue Requirement with ff&u @ 0.009602			$20,990
11. Bundled and DA Load		83,356	

[7] PG&E's portfolio of resources excludes DWR contracts allocated to PG&E.

PG&E's Forecast of the 2006 Ongoing CTC Revenue Requirement for Bundled & DA Customers Using the Total Portfolio Method			
Item	**MPR**	**(GWh)**	**($000)**
12. CGDL and MDL		687	
13. Total Load		84,043	
14. Bundled and DA Revenue Requirement (99.18% of Total)			20,818
15. MTCBA Bundled & DA Subaccount Balance			(21,849)
16. Total Ongoing CTC Revenue Requirement			**(1,031)**
Source: PG&E Supplement filed November 2, 2005, Table 6-2.			

Line 7 in the above Tables shows zero above-market costs, despite the arithmetic calculation of a negative number. PG&E argues that ongoing CTC cannot be negative, except when necessary to amortize an overcollection in the MTCBA as shown in Lines 14 - 16 of the above Table. The issue of negative CTC is addressed in more detail, *infra*.

PG&E used the "statutory method" to forecast the ongoing CTC revenue requirement for customer generation DL (CGDL) and municipal DL (MDL) customers. The statutory method differs from the total portfolio method in that the total portfolio method includes URG, while the statutory method does not. PG&E's forecast of the ongoing CTC revenue requirement for CGDL and MDL using the statutory method is shown in the following Table:

PG&E's Forecast of the 2006 Ongoing CTC Revenue Requirement for CGDL & MDL Customers Using the Statutory Method			
Item	**MPR**	**(GWh)**	**($000)**
1. URG		0	0
2. QFs and PPAs Eligible for Ongoing CTC		18,924	$1,896,894
3. Irrigation District & Water Agencies		3,741	88,476
4. **Statutory Portfolio Generation & Cost**		22,665	1,985,370

PG&E's Forecast of the 2006 Ongoing CTC Revenue Requirement for CGDL & MDL Customers Using the Statutory Method			
Item	**MPR**	**(GWh)**	**($000)**
5. MPR Benchmark ($/MWh)	$72.70		
6. Market Cost (Line 4 (GWh) x Line 5)			$1,647,746
7. Above-Market Costs (Line 4 – Line 6)			337,624
8. Restructuring Costs			20,790
9. Total Statutory Revenue Requirement			358,414
10. Revenue Requirement with ff&u @ 0.009602			$361,855
11. 2006 Bundled and DA Load		83,356	
12. MDL		588	
13. CGDL		99	
14. Total Load		84,043	
15. MDL Ongoing CTC Rev. Req. (0.70% of Total)			**2,533**
16. MTCBA - MDL Subaccount Balance			TBD
17. Total MDL Ongoing CTC Rev. Requirement			**$2,533**
18. CGDL Ongoing CTC Rev. Req. (0.12% of Total)			$ **426**
19. MTCBA - CGDL Subaccount Balance			TBD
20. Total CGDL Ongoing CTC Rev. Requirement			**$ 426**
21. Total DL Ongoing CTC Revenue Requirement			**$2,959**
Source: PG&E Supplement filed November 2, 2005, Tables 6-3 and 6-4.			

The MTCBA balance for DL customers will be addressed in R.02-01-011. Therefore, Lines 16 and 19 in the above Table do not include a forecast of the 2005 year-end balance in the MTCBA for CGDL and MDL customers.

The following Table summarizes PG&E's forecast of its 2006 ongoing CTC revenue requirement for bundled, DA, CGDL, and MDL customers:

Summary of PG&E's Forecast of the Total 2006 Revenue Requirement for Ongoing CTC		
Customer Group	**Above-Market Cost ($000)**	**Ongoing CTC ($000)**
Bundled and DA	0	(1,031)
MDL	2,362	2,533
CGDL	398	426
Total	$2,760	$1,928

C. Rate Design

Application 05-06-007 contains a detailed rate design proposal for (1) allocating the forecast revenue requirement for the ERRA and ongoing CTC among customer classes, and (2) setting rates for each customer class to recover the allocated revenue requirement. PG&E represents that its rate design proposal is consistent with the Rate Design Settlement Agreement (RDSA) adopted in D.04-02-062.

PG&E notes that the Commission is considering rate designs that differ from the RDSA in PG&E's pending 2003 General Rate Case (GRC) proceeding (A.04-06-024). If a decision regarding PG&E's rate design is issued in the GRC proceeding before the instant proceeding, PG&E recommends the rate design adopted by the GRC decision be used to recover PG&E's ERRA and ongoing CTC revenue requirement.

4. Position of the Parties and PG&E's Response

A. Position of the Parties

CMUA, Merced & Modesto, NCPA, and SSJID (collectively, the Opposition Parties) oppose PG&E's use of the statutory method to forecast the ongoing CTC revenue requirement for DL customers. They contend that the total portfolio method should be used for the following reasons. First, the

Opposition Parties assert that D.05-01-035 requires the total portfolio method. Second, PG&E uses the total portfolio method for bundled and DA customers, and PG&E should do the same for DL customers. Third, the statutory method results in a much higher CTC rate in 2006 compared to the total portfolio method. The Opposition Parties argue that it is unlawfully discriminatory to charge DL customers a much higher CTC rate. Finally, the Opposition Parties represent that other investor-owned utilities charge a single CTC rate to all customers, and PG&E should do the same.

The Opposition Parties and AReM assert that the total portfolio method results in a negative revenue requirement for ongoing CTC in 2006, which PG&E arbitrarily set to zero. Negative CTC occurs when the market benchmark price for electricity exceeds the average cost of PG&E's generation resources. The following Table shows the calculation of the negative CTC revenue requirement before amortization of the MTCBA:

2006 Negative Ongoing CTC Revenue Requirement for Bundled, DA, and DL Customers Using the Total Portfolio Method			
Description	**MPR**	**(GWh)**	**($000)**
1. URG		29,630	$1,094,658
2. QFs & Purchased Power Eligible for Ongoing		18,924	1,896,894
3. Irrigation Districts & Water Agencies		3,741	88,476
4. **Total Portfolio Generation & Cost**		**52,295**	**3,080,028**
5. Portfolio Average Cost ($/MWh)	$58.90		
6. Benchmark ($/MWh) Using MPR	$72.70		
7. Market Cost (Line 6 (GWh) x Line 4)			$3,801,847
8. Above Market Costs (Line 4 – Line 7)			($721,819)
9. QF Contract Restructuring Costs			20,790
10. Total Portfolio Rev. Requirement (Cost x ff&u)			($701,029)
11. Bundled and DA Load		83,356	
12. CGDL and MDL Loads		687	

2006 Negative Ongoing CTC Revenue Requirement for Bundled, DA, and DL Customers Using the Total Portfolio Method			
Description	**MPR**	**(GWh)**	**($000)**
13. Total Load		84,043	
14. Bundled and DA Revenue Requirement (99.18% of Total)			($695,299)
15. CGDL and MDL Revenue Requirement (0.82% of Total)			($5,730)
Source: PG&E Supplement filed November 2, 2005, Table 6-2.			

The Opposition Parties argue that DL customers should benefit from negative CTC just as other customers do. Otherwise, DL customers will pay only the cost of ongoing CTC but receive none of the benefits of negative CTC.

Merced & Modesto recommend that negative CTC be used to offset positive CTC over a period of years. In the case of MDL customers, the negative CTC for 2006 could offset the positive CTC owed by MDL customers for 2004 and 2005. Merced & Modesto emphasize that they are not proposing that other customers pay negative CTC to MDL customers, only that ongoing CTC be netted from one year to the next.

AReM recommends that the issue of negative CTC be deferred to R.02-01-011 or a similar proceeding where the matter can be considered for all utilities and where all interested parties can participate. AReM also recommends that the ongoing CTC rate be set at zero pending further consideration of the negative CTC issue, and that PG&E track the ongoing CTC revenue requirement (including negative CTC) for later disposition.

AReM notes that ongoing CTC is part of the CRS, and that the purpose of the CRS is to ensure that DA customers bear a fair share of "above-market" costs so as to keep bundled customers indifferent to the migration of customers to DA service.[8] AReM states that the relationship between negative CTC and bundled customer indifference deserves careful thought in R.02-01-011. One possibility, according to AReM, is to use negative CTC to offset other CRS components.

CMUA, Modesto & Merced, and NCPA contend that the principle of bundled customer indifference applies to both positive and negative CTC. They state that the Commission kept bundled customers indifferent by requiring DL customers to pay a fair share of ongoing CTC costs. Now that there are negative CTC costs, these parties believe that the principle of customer indifference requires that DL customers receive a fair share of the negative CTC.

B. PG&E's Response

PG&E opposes the use of the total portfolio method to determine ongoing CTC for DL customers. PG&E maintains that D.05-02-040 and D.05-01-031, issued in PG&E's two previous ERRA/CTC forecast proceedings, used the statutory method for DL customers.

PG&E contends that D.05-01-035 does not require the use of the total portfolio method for all DL customers. This is because D.05-01-035 does not address ongoing CTC for MDL customers. Further, D.05-01-035 is inconsistent with the following decisions that used the statutory method for DL customers: D.05-02-040, D.05-01-031, and D.03-04-030. Given this inconsistency, and the fact that D.05-01-035 does not address ongoing CTC for MDL customers, PG&E concludes that D.05-01-035 does not support the use of the total portfolio method to calculate ongoing CTC for DL customers.

[8] D.02-11-022, *mimeo.*, pp. 1-3, 23-25, and 64.

PG&E maintains that the purpose of both the statutory method and the total portfolio method is to calculate the portion of PG&E's electric power costs that is above market. If either method yields a negative number, it means there are no above-market costs and that the above-market component of ongoing CTC must be set to zero. PG&E adds that restructuring costs are a separate element of ongoing CTC and should not be netted against negative above-market costs.

PG&E opposes the use of negative above-market costs (negative CTC) to offset other costs. PG&E states that the use of negative CTC to reduce non-bundled customers' obligation for other costs will force bundled customers to pay more of these other costs. PG&E opines that such a result would be unfair.

PG&E disputes the notion that DL customers that pay positive CTC should receive negative CTC. PG&E states that DL customers who leave PG&E must pay the above-market costs that PG&E incurred on their behalf before they left. Otherwise, PG&E's remaining customers would have to bear more than their fair share of above-market costs. Conversely, once DL customers leave, PG&E believes they are not entitled to the benefits enjoyed by the remaining customers.

PG&E disagrees that the "indifference standard" adopted in D.02-11-022 requires DL customers to receive a share of negative CTC. That decision explicitly states that it does not resolve the treatment of below-market costs. Consequently, the indifference standard does not apply to negative CTC.

Finally, PG&E opposes AReM's recommendation to address the issue of negative CTC in R.02-01-011. However, if the Commission decides to address the issue elsewhere, then PG&E recommends that the above-market component of the ongoing CTC adopted in the instant proceeding to be set to zero.

5. Discussion

A. Forecast Revenue Requirement for the ERRA

There is no opposition to PG&E's request to adopt a forecast ERRA revenue requirement of $2.821 billion for 2006. PG&E's request is supported by detailed and unrebutted testimony.

The forecast ERRA revenue requirement must be reduced by the amount of costs that are transferred from the ERRA to the MTCBA. PG&E forecasts $23.8 million of ERRA costs will be transferred to the MTCBA in 2006.[9] Today's Decision, *infra*, finds that $361.9 million of ERRA costs will be transferred in 2006. Therefore, the forecast ERRA revenue requirement adopted by today's Decision is $2.483 billion (i.e., $2,820,901,000 less [$361,855,000 - $23,777,000]).

The forecast ERRA revenue requirement adopted by today's Decision will be trued up with PG&E's actual ERRA costs incurred during 2006. Any undercollection or overcollection of PG&E's actual ERRA costs during 2006 will be flowed through to PG&E's bundled service customers. The Commission will also review PG&E's actual ERRA costs incurred during 2006. Today's Decision does not prejudge this review.

B. Forecast Revenue Requirement for the Ongoing CTC

There is opposition to two aspects of PG&E's forecast revenue requirement for the ongoing CTC. First, several parties object to PG&E's use of two methods to calculate ongoing CTC. Second, several parties oppose PG&E's refusal to recognize negative CTC. We address these two issues, *infra*.

The uncontested aspects of PG&E's forecast revenue requirement for the ongoing CTC are supported by detailed and unrebutted testimony. In addition,

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[9] PG&E Supplement filed on November 2, 2005, Table 6-6.

the parties agreed to use the MPR to determine the above-market component of ongoing CTC. Based on the foregoing, we will adopt the uncontested aspects of PG&E's forecast revenue requirement for ongoing CTC.

i. Method for Determining Ongoing CTC

PG&E used two methods to forecast its ongoing CTC revenue requirement -- the total portfolio method for bundled and DA customers, and the statutory method for DL customers. The other parties contend that the total portfolio method should be used to determine ongoing CTC for DL customers.

We will rely on D.05-10-047, D.05-10-046, and D.05-01-035 to determine how ongoing CTC should be calculated. The Commission concluded in these decisions that ongoing CTC is limited to the costs specified in § 367(a)(1) – (6), which is the same as saying that the statutory method should be used to calculate ongoing CTC. The Commission also determined that the total portfolio method should be used to calculate the indifference costs included in the CRS, but has no bearing on the calculation of ongoing CTC.[10]

It appears that PG&E and the other parties mistakenly believe that the Commission previously used the total portfolio method to calculate ongoing CTC for at least some customer groups. As a result of the parties' misperception, most of their arguments regarding whether or not the total portfolio method should be used to calculate ongoing CTC are inapposite.

The following Table shows the adopted 2006 forecast revenue requirement for ongoing CTC for all PG&E customer categories using the statutory method:

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[10] D.05-10-047, *mimeo.*, p. 3; D.05-10-046, *mimeo.*, pp. pp. 3, 5-8; and D.05-01-035, *mimeo.*, pp. 2-3.

Adopted Forecast of PG&E's 2006 Ongoing CTC Revenue Requirement for Bundled, DA, CGDL & MDL Customers Using the Statutory Method			
Description and Statutory Authority	**MPR**	**(GWh)**	**($000)**
1. QF & Other Purchased Power Costs (§ 367(a)(2))		18,924	1,896,894
2. Irrigation District & Water Agencies (§ 367(a)(2))		3,741	88,476
3. Subtotal: Generation & Cost		22,665	1,985,370
4. MPR Benchmark ($/MWh)	$72.70		
5. Market Cost (Line 3 (GWh) x Line 4)			$1,647,746
6. Above-Market Costs (Line 3 - Line 5)			337,624
7. QF Restructuring Costs (§ 367(a)(2))			20,790
8. Subtotal Costs (Line 6 + Line 7)			$358,414
9. **Statutory Rev. Req. (**Cost + ff&u @ 0.009602)			$361,855
10. 2006 Bundled and DA Load		83,356	
11. MDL and CGDL		687	
12. Total Load		84,043	
13. Bundled & DA Rev. Requirement (99.18% of Total GWh)			$358,897
14. MTCBA Subaccount Balance for Bundled & DA			(21,849)
15. Total Bundled & DA Ongoing CTC Revenue Requirement			**$337,048**
16. DL Ongoing CTC Rev. Req. (0.82% of Total GWh)			$2,958
17. MTCBA-DL Subaccount Balance			TBD **(a)**
18. Total DL Ongoing CTC Revenue Requirement			**$2,958**
19. Total Ongoing CTC Revenue Requirement			**$340,006**
(a) MTCBA balance for DL for past periods will be addressed in R.02-01-011.			
Source: PG&E Supplements filed on (i) Nov. 2, 2005, Tables 6-2, 6-3, and 6-4; and (ii) Nov. 9, 2005.			

The statutory method used by today's Decision to determine the ongoing CTC revenue requirement results in the same CTC rate on a per kWh basis for all customers obligated to pay the CTC. The actual CTC rate for individual customer classes will differ in practice due to amortization of any over- or undercollection of the previous CTC revenue requirement allocated to a customer class, limitations on the rates paid by certain customer classes, etc.

We acknowledge that D.05-01-031, issued in PG&E's 2004 ERRA/CTC forecast proceeding, might have created the impression that there are two methods for calculating ongoing CTC because the decision adopted two different CTC rates – one for DL customers, and the other for bundled and DA customers.[11] However, it was not our intention to adopt two different methods. We stated in Footnote 11 of D.05-01-031 that the calculation of ongoing CTC must be based on § 367(a)(1) - (6). Thus, we signaled our intent that only the statutory method should be used to calculate ongoing CTC.

Finally, it is obvious that PG&E believes its tariffs allow PG&E to calculate ongoing CTC using the total portfolio method for bundled and DA customers, and the statutory method for DL customers. To ensure that PG&E's tariffs reflect today's Decision, we will require PG&E to file revised tariffs which state that only the statutory method shall be used to calculate ongoing CTC.

In their comments on the proposed decision, BART, Merced & Modesto, and NCPA argue that § 367(b) requires the use of the total portfolio method to determine ongoing CTC. We disagree. In D.05-10-046, we held that § 367(b) does not address the recovery of ongoing CTC.[12] In light of this holding, we conclude that § 367(b) does not require the use of the total portfolio method.

SSJID's comments on the proposed decision assert that D.05-10-047, D.05-10-046, and D.05-01-035, which are decisions on rehearing, upheld PG&E's rates for ongoing CTC that were calculated using the total portfolio method. SSJID contends that these decisions show that the total portfolio method should be used to determine ongoing CTC. We disagree. Each of the decisions cited by

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[11] D.05-01-031, Ordering Paragraphs (OPs) 4 and 5.

[12] D.05-10-046, *mimeo.*, pp. 3-4.

SSJID explicitly states that the statutory method should be used to determine ongoing CTC.[13]

Several parties' comments on the proposed decision ask for guidance regarding the use of the total portfolio method to determine the indifference costs included in the CRS. In general, these parties are concerned that the use of the statutory method to calculate ongoing CTC may have unintended effects on other components of the CRS. We decline to address in today's Decision the details for determining any of the components of the CRS other than ongoing CTC, as this matter is beyond the scope of the instant proceeding. Issues related to the determination of other CRS components will be addressed in R.02-01-011. We note that there is a working group currently underway in R.02-01-011 to refine the methodology for determining CRS obligations. Today's Decision does not foreclose the ability of this working group to propose changes to the DA CRS calculation methodology to address the effects of today's Decision on other components of CRS.

CMUA's comments also ask the Commission to reconcile the use of the statutory method to calculate PG&E's CTC rate with the Commission's use of the total portfolio method to calculate SCE's CTC rate. We decline to reconcile in today's Decision the differences, if any, between the calculation of PG&E's CTC versus the calculation of SCE's CTC. This is because the record for the instant

[13] D.05-10-047, *mimeo.*, p. 3 (citing D.05-10-046), D.05-10-046, *mimeo.*, pp. 3-4, 5, 6, and 7-8, and D.05-01-035, *mimeo.*, p. 3.

proceeding lacks many details regarding the calculation of SCE's CTC.[14] CMUA may raise this issue in other proceedings, as appropriate.

BART argues in its comments that Senate Bill (SB) 1201[15] requires the use of the total portfolio method to determine the CTC applicable to power that BART acquires from local publicly owned utilities. We disagree. SB 1201 modified § 701.8 to require PG&E and other electrical corporations to deliver power from local publicly owned utilities to BART without discrimination. There is nothing in SB 1201 that addresses how the CTC should be determined. We note, however, that the Senate Bill Analysis of SB 1201 states:

> As an adjunct to permitting BART to purchase electricity from a municipal utility, this bill would extend the CTC exemption to BART load served by a municipal utility.

BART is exempt from ongoing CTC with respect to federal preference power pursuant to § 374(b). Based on the previously cited provision in the Senate Bill Analysis of SB 1201, we conclude that SB 1201 extended the CTC exemption to BART load that is served by local publicly owned electric utilities. Other power, such as supplemental power that BART purchases from PG&E, remains subject to ongoing CTC.

ii. Negative Ongoing CTC

Today's Decision determines, *supra*, that the above-market component of PG&E's ongoing CTC revenue requirement for 2006 is a positive amount.

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[14] As stated previously in today's Decision, ongoing CTC is limited to the costs specified in § 367(a)(1) – (6). PG&E's ongoing CTC rate adopted by today's Decision complies with this requirement. The record for the instant proceeding is inadequate to determine whether, and to what extent, SCE's ongoing CTC rate deviates from this requirement.

[15] Statutes 2004, Chapter 613.

However, in order to avoid future litigation on the treatment of negative above-market costs (referred to hereafter as negative CTC), we will provide guidance on how to treat negative CTC.

Beginning in 2006 and subsequent years, negative CTC shall be netted against positive above-market costs included in ongoing CTC (referred to hereafter as positive CTC). The use of negative CTC to offset positive CTC is reasonable because it results in a more accurate measurement of the total amount of above-market costs over time.

The MTCBA shall be used to track negative CTC beginning in 2006. Thus, any negative CTC that occurs in 2006 and subsequent years may only be used to offset positive CTC during these years.[16] No interest shall accrue on a negative CTC balance in the MTCBA. The use of negative CTC to offset positive CTC shall be flowed through to customers on a per kWh-basis.[17] The tracking of negative CTC shall cease when all ongoing CTC costs have been recovered. Any remaining negative CTC balance in the MTCBA shall have no further effect on cost allocation or rates.

Negative CTC shall only be used to offset positive above-market costs; it shall not be used to offset other components of the ongoing CTC (e.g., QF restructuring costs) or other components of the CRS.[18] This is because negative CTC does not provide any cash. Thus, negative CTC cannot be used to offset

[16] When negative CTC is used to offset positive CTC, there should be an offsetting entry in the ERRA for regulatory accounting purposes.

[17] Negative CTC should be tracked by bundled, DA, CGDL, and MDL customer categories. To reduce administrative complexity, there is no need to track negative CTC by vintage or individual customers.

[18] Today's Decision does not prejudge how to treat any negative amounts that may result when the total portfolio method is used to calculate the indifference costs recovered via the CRS.

costs that involve actual cash expenditures (e.g., QF restructuring costs) because negative CTC does not provide any cash to pay those costs.[19]

In its comments on the proposed decision, PG&E argues that it is improper to pay negative CTC to DL customers for the same reasons the Commission's Energy Division previously determined that it was improper to pay a power exchange credit to DL customers. In response to PG&E's comments, we clarify that today's Decision does not result in the payment of negative CTC to any customers. Rather, today's Decision merely expands the period of time for measuring CTC, so that negative CTC in future years is used to offset positive CTC in future years. Any negative CTC that is not offset by positive CTC will remain in the MTCBA where it will have no effect on customers.

C. Rate Design

PG&E presented a detailed rate design proposal to recover its forecast revenue requirement for the ERRA and ongoing CTC. PG&E's rate design proposal is unopposed, supported by unrebutted testimony, and consistent with Commission precedent. Therefore, we will adopt PG&E's rate design proposal.

In accordance with the AET process, all recent Commissions decisions affecting PG&E's electric rates will be implemented through one consolidated rate change on January 1, 2006, including today's Decision. No further action on electric rates is necessary in today's Decision. The AET process includes amortization of the estimated 2005 end-of-year balances in the ERRA and

[19] Although positive CTC represents actual cash expenditures, it is appropriate to use negative CTC to offset positive CTC because doing so results in a more accurate measurement of the total amount of above-market costs over time.

MTCBA. PG&E will file a supplemental AET advice letter in December 2005 to update the estimated end-of-year balances adopted by today's Decision.

The rate design adopted by today's Decision is consistent with the RDSA adopted in D.04-02-062. We note that the Commission may adopt another rate design in PG&E's pending 2003 GRC Phase 2 proceeding (A.04-06-024) that differs from the RDSA. If a final decision in the GRC proceeding is issued before today's Decision, the rate design adopted in the GRC decision should be used to set rates to recover the revenue requirement authorized by today's Decision.

D. Issues Not Addressed

Today's Decision does not address the issue of whether new MDL included in PG&E's forecast revenue requirement for ongoing CTC qualifies under § 369 for an exemption from CTC, as this issue has a *de minimis* impact on PG&E's ongoing CTC rate for MDL. Accordingly, today's Decision does not prevent any party from raising this issue in another proceeding.

Merced, Modesto, and CMUA filed applications for rehearing of D.05-02-040 and D.05-01-031, which were issued in PG&E's 2005 and 2004 forecast ERRA/CTC proceedings, respectively. These applications were resolved in D.05-10-047 and D.05-10-046. Today's Decision does not address the issues raised in the applications for rehearing and resolved in D.05-10-047 and D.05-10-046. The revenue requirement adopted by today's Decision is consistent with D.05-10-047 and D.05-10-046, and will be subject to adjustment and true-up, as necessary, if D.05-10-047 and/or D.05-10-046 are successfully appealed.[20]

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[20] On November 22, 2005, Merced and Modesto jointly filed a petition for writ of review of Decision Nos. 05-10-047, 05-10-046, 05-02-040, and 05-01-031.

6. Comments on the Proposed Decision

The proposed decision of the Administrative Law Judge (ALJ) in this matter was mailed to the parties in accordance with § 311(d) and Rule 77.1. Comments regarding the proposed decision were filed on December 5, 2005, by BART, CMUA, Merced & Modesto, NCPA, PG&E, and SSJID. Reply comments were filed on December 12, 2005, by these same parties and by AReM and CLECA. These comments have been reflected, as appropriate, in the final Decision adopted by the Commission.

7. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Timothy Kenney is the assigned ALJ for this proceeding.

8. Findings of Fact

1. In A.05-06-007, as supplemented, PG&E asks the Commission to adopt the following: (i) a 2006 ERRA forecast revenue requirement of $2.821 billion, (ii) a 2006 ongoing CTC forecast revenue requirement of $1.9 million, and (iii) PG&E's proposed rate design to recover the aforementioned revenue requirement.

2. PG&E provided detailed testimony to explain and support its requests in A.05-06-007 described in the previous Finding of Fact (FOF). Except as noted in FOF 5, there is no opposition to A.05-06-007.

3. PG&E used the total portfolio method to forecast the ongoing CTC revenue requirement for bundled and DA customers, and the statutory method to forecast the ongoing CTC revenue requirement for DL customers.

4. Although the total portfolio method arithmetically produces a negative revenue requirement for ongoing CTC in 2006, PG&E set the revenue requirement at zero (before taking into consideration QF restructuring costs and amortization of the MTCBA balance).

5. Several parties recommend that (i) the total portfolio method be used to calculate the ongoing CTC revenue requirement for all customers, and (ii) negative CTC be used to offset other elements of PG&E's revenue requirement. AReM recommends that the disposition of negative CTC be decided in R.02-01-011. PG&E opposes these recommendations.

6. PG&E's forecast revenue requirement for ongoing CTC in 2006 using the statutory method for all customer groups is $340.0 million.

7. PG&E's current tariffs allow PG&E to calculate ongoing CTC using the total portfolio method for bundled and DA customers, and the statutory method for CGDL and MDL customers.

8. Today's Decision does not address the mechanics and procedures for determining the CRS.

9. Pursuant to Resolution E-3906, which established the AET process, the revenue requirement adopted by today's Decision will be (i) updated in December 2005 to reflect revised estimates of the end-of-year balances in the ERRA and MTCBA using data through November 30, 2005; (ii) consolidated with the revenue requirement effects of other recent Commission decisions; and (iii) implemented in rates on January 1, 2006.

10. The rate design proposed by PG&E in A.05-06-007 and adopted by today's Decision is consistent with the RDSA adopted in D.04-02-062. However, if a different rate design is adopted in PG&E's pending 2003 GRC Phase 2 proceeding (A.04-06-024) that differs from the RDSA, PG&E proposes to use the rate design in the GRC decision to recover the revenue requirement authorized by today's Decision. There is no opposition to PG&E's proposal.

9. Conclusions of Law

1. PG&E should be authorized to recover a 2006 forecast revenue requirement for the ERRA and the ongoing CTC in the amount of $2.483 billion and $340.0 million, respectively.

2. Decisions Nos. 05-10-047, 05-10-046, and 05-01-035 determined that (i) ongoing CTC is limited to the costs specified in § 367(a); (ii) the statutory method should be used to calculate ongoing CTC; (iii) the total portfolio method should be used to determine the amount of indifference costs recovered via the CRS; and (iv) ongoing CTC is included in the CRS as a part of a blended charge.

3. PG&E's tariffs should be revised to state that only the statutory method shall be used to calculate ongoing CTC.

4. Issues regarding the determination of the CRS should be addressed in R.02-01-011.

5. SB 1201 exempts BART from the ongoing CTC with respect to BART load that is served by (i) federal preference power, and (ii) power from local publicly owned electric utilities. Other power, such as supplemental power that BART purchases from PG&E, remains subject to the ongoing CTC.

6. If the statutory method results in negative above-market costs, this negative amount should offset positive above-market costs included in ongoing CTC to the extent set forth in the body of today's Decision.

7. The revenue requirement identified in Conclusion of Law No. 1 should be recovered via the rate design proposed by PG&E in A.05-06-007. However, if a final decision in PG&E's 2003 GRC Phase 2 proceeding is issued before today's Decision, the rate design adopted in the GRC decision should be used to recover the revenue requirement authorized by today's Decision.

8. Today's Decision does not address whether new MDL is exempt from ongoing CTC pursuant to § 369. Parties may raise this issue in other proceedings.

9. The revenue requirement authorized by this Decision is subject to adjustment and true-up, as necessary, in the event that D.05-10-047 and/or D.05-10-046 are successfully appealed.

10. The following Order should be effective immediately so that PG&E can begin to recover on January 1, 2006, the revenue requirement authorized therein.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) is authorized to recover a 2006 forecast revenue requirement for the Energy Resource Recovery Account (ERRA) in the amount of $2.483 billion.

2. PG&E is authorized to recover a 2006 forecast revenue requirement for the ongoing Competition Transition Charge (CTC) in the amount of $340.0 million.

3. The revenue requirement authorized by this Order may be revised in accordance with the Annual Electric True-Up (AET) process to update estimates of the 2005 end-of-year balances in the (i) ERRA, and (ii) modified Transition Cost Balancing Account subaccounts for bundled and direct access customers.

4. PG&E may implement rates on January 1, 2006, in accordance with the AET process to recover the revenue requirement authorized by this Order

5. The revenue requirement authorized by this Order shall be recovered through the rate design proposed in Application (A.) 05-06-007. However, if a final decision in Phase 2 of PG&E's 2003 general rate case (GRC) in A.04-06-024 is

issued before this Order, the rate design adopted in the GRC decision shall be used to recover the revenue requirement authorized by this Order.

6. Ongoing CTC shall be calculated in accordance with the statutory method described in the body of this Order. If the above-market component of ongoing CTC is negative, this negative amount may offset positive above-market costs included in ongoing CTC to the extent set forth in the body of this Order.

7. PG&E shall file revised tariffs which clearly indicate that only the statutory method shall be used to calculate ongoing CTC. PG&E shall file the revised tariffs within 10 days from the date this Order is mailed.

8. Application 05-06-007 is granted and denied to the extent set forth in the previous Ordering Paragraphs.

9. Application 05-06-007 is closed.

This Order is effective today.

Dated December 15, 2005, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
SUSAN P. KENNEDY
DIAN M. GRUENEICH
JOHN A. BOHN
Commissioners